COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

	)	
Boston Edison Company, Cambridge	)	**D.T.E. 03-121**
Electric Light Company, and	)	
Commonwealth Electric Company	)	
d/b/a NSTAR Electric	)	
	)	

DIRECT TESTIMONY OF ALVARO E. PEREIRA

FOR THE MASSACHUSETTS DIVISION OF ENERGY RESOURCES

I. INTRODUCTION

Q. Please state your name, business address and employment position.

A. My name is Alvaro E. Pereira. My business address is 70 Franklin Street, Boston, MA 02110. I am Manager of Energy Supply and Pricing at the Commonwealth of Massachusetts Division of Energy Resources (DOER), a position I assumed in December of 1999. I have overall responsibility for the Division's analytical and modeling work as well as primary responsibility for policy development regarding energy markets and reliability.

Q. Please describe your education and professional background.

A. Prior to my current position, I was Senior Economist at the Division of Energy Resources. As part of this position, as well as my current work, I have been responsible for electricity and gas industry economic analyses and forecasts and conducted economic and market impacts of energy-related policies and investments. I have also provided technical support and analysis of utility rate design and stranded costs, performance-based rates and benchmarking, market power, wholesale-market bidding behavior and procurements, and economic impacts of energy efficiency and environmental policies, among other areas. I came to DOER from the Massachusetts Institute of Technology (MIT), where I was Visiting Lecturer and Research Associate from September 1991 to February 1999. While at MIT, I taught graduate-level courses in Transportation Economics and Regional Economic Methods and Modeling and completed research studies in the areas of industrial business processes, transportation economics, and the economic modeling of environmental impacts, among others. My education consists of Bachelor degrees in Economics and Finance from the University of Massachusetts at Amherst, and a Master's Degree in Civil Engineering and a Ph.D. in Urban and Regional Economics from MIT.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present DOER's concerns about certain aspects of the NSTAR standby rate proposal in this proceeding. As indicated in our comments submitted on February 17, 2004, DOER opposes the NSTAR proposed rate on the following grounds:

1. The proposed rates do not represent an accurate accounting of the distribution and transmission costs actually incurred in providing service to distributed generation customers.
2. The proposed rates do not take into account the full benefits of distributed generation to the electric system and its users.
3. The proposed rates, if enacted, will hinder the development and efficient use of distributed generation, which is especially critical to the local economy.
4. The proposed rates are incompatible with current state policy regarding the development of clean and renewable generation technology.

II. The Proposed Rates Are Not Adequately Supported By A Cost of Service and Present a Faulty Rate Design

Q. Please describe the cost basis and rationale for the proposed rates for customers with on-site generation.

A. The Companies have provided very little cost support for the proposed rates. Their proposal is merely based upon current, non-standby rates with an explanation from the Companies' witness that "under current standby service, standby service customers do not pay the full cost that is incurred by the Company to provide standby service, resulting in a subsidy of standby service customers by other all-requirements customers (Response to Information Request DOER-1-18)." This approach raises two errors, first, it assumes that the Companies were recovering their full cost of service under the current rates and, second, that the customers with distributed generation impose new or different costs on the Companies. Neither premise has been proven in this filing. The overall rationale of the Companies seems to be that, absent the proposed rates, other customers will be subsidizing the distributed generation customers. Without an adequate showing of cost causation and cost recovery under existing rates, it is impossible to conclude that there will be an increase in cross-subsidization among classes of customers than may already exist under the current rate structure. In fact, there are studies that suggest such customers may be contributing a benefit to the system and thereby the non-standby customers by the presence of the on-site generation.

Q. How would cost of service information test the assumptions about cost recovery and cross-subsidization?

A. In the last available allocated cost of service studies (1992) for the Company, rates of return were quite different among classes. For example, according to the 1992 study for Boston Edison, the Company earned a rate of return of 8.74% for total residential service compared to 10.19% for total general service. The lack of an updated allocated cost of service study prohibits a more detailed study of the issue of cost subsidization, which is critical to the premise that rates should be based on the actual costs incurred to provide service to different customers.

Q. Do current NSTAR rates represent recovery of cost of service for all rate classes?

A. In theory, yes, but without an updated cost of service we have no way of knowing whether the Companies are over or under collecting. Further, even if we did, we would only know in an aggregate sense unless there was an allocation study among the rate classes as well. As mentioned above, rates of return differ among rate classes for important reasons. Hence, it is incorrect to state that current standby rates do not represent an accurate recovery of cost of service and thus need to be changed any more than current non-standby rates may accurately recover costs to provide service. The Company's logic implies that a number of rate classes would have be adjusted.

Q. Do current NSTAR rates unfairly discriminate against other customers by requiring them to subsidize other customers?

A. No, but as discussed above, subsidization does exist. There is the possibility that some standby customers may be subsidized by non-standby customers of the same rate class. It is also possible that the converse may be true. The Company, however, has not proven that there are enough subsidization problems caused by current rates to prompt the Company to propose changes to existing standby charges. In addition, the presence of cross-subsidization, by itself, has not proven to be cause to alter rates. It's also important to note that there is no rate impact on non-standby customers unless the Company comes in for a rate increase and the Department approves that rate. In the interim, the Company's shareholders would bear any such costs, if they exist, and even then only to the extent the overall rate revenue is less than the cost of service.

Q. What is your interpretation of the phrase, "DG should pay an appropriate share of distribution system costs?"

A. Determining an appropriate share of distribution system costs would entail a level of analysis and data gathering that the Company has either not performed or does not wish to submit.[1] I believe that the Company needs to account for location-specific costs and any potential benefits from installation of DG. Neither of these two areas have been investigated in the Company's filing. The Company has basically stated that costs for DG customers are the same as for non-standby customers. Such a statement does not account for locational differences in distribution-system costs and for locational differences in benefits due to DG installation.

Q. Do the proposed rates feature any cost shifting to other customers?

A. Possibly. Even assuming that "the costs incurred to provide standby distribution service over this portion of the company's distribution system are exactly the same as the costs necessary to provide 'normal' distribution service to customers who purchase all of their electricity 'outside the fence'" (page 13 of LaMontagne Direct Testimony), the Company's current rates were designed to collect all distribution-system costs and not simply those attributable to certain portions of the system. This can be shown by the most recently available cost-of-service studies that were provided by the Company. That is, as demand grows, utility companies have tended to increase the system and collect these additional costs from all customers, regardless of where these costs were incurred.

Q. Should rates be more fixed for DG customers, as proposed by NSTAR?

A. No. The Company has not provided any cost causation arguments that standby customers incur a greater share of fixed costs than non-standby customers or that costs incurred by

[1] At the time of this filing DOER was still awaiting a complete response to numerous discovery questions, including (but not limited to) DOER 1-13, AG 1-19, AG 1-20, DTE 3-1, and 4-1.

standby customers are more fixed in nature. Clearly, there may be concerns of revenue recovery, but the Company has not stated that a loss of revenues is a motivation for the proposed rates. The addition of DG may affect the revenues received by the utility company, but short of interconnection costs that are not under the purview of the proposed rates, [2] I have seen no evidence that documents a shift from variable costs to fixed costs for standby customers. It should be noted that reductions in revenue can occur for other reasons, such as demand-side management, installation of EE measures, and reductions in load due to downsizing or other adjustments in a customer's business operations. Customers that have such events do not suffer a shift in rates as would customers of the proposed standby rates.

Q. Describe how cost recovery and cost causation differ between customers with energy efficiency and customers without energy efficiency.

A. From the perspective of the Company's treatment of rate design, there is no difference. Consider a customer that installs EE measures that are quite beneficial but are not large enough to cause a shift of costs to a different rate class. After installation, that customer will enjoy a whole host of bill savings and will provide systemwide benefits in terms of reliability, environment, and avoided transmission and distribution (T&D) costs, among others. Avoided T&D is a category of benefits that has been recognized by the Department and is included by all EE program administrators in the Commonwealth to screen their various EE programs for cost-effectiveness. Although one would not expect the bill savings amount and the dollar impact of EE on avoided T&D to be exactly equivalent, they are directionally equivalent. Thus, a customer that installs EE equipment causes costs to be saved by the utility company and enjoys private savings as a result. The proposed standby rates do not follow this logic.

Q. Is it possible that the cost studies would show that current standby customers with on-site generation would pay more than they would under their current rates?

[2] The state's newly approved interconnection standards (DTE 02-38, 2004) compensates the distribution companies for upgrades required from such interconnections on a project-specific basis.

A. Yes, DOER has asked in a timely fashion for the Company to provide information that would assist in the answer to this question (Information Request DOER-1-13). Unfortunately, the Company was unable to provide a timely response to this request. I may supplement my testimony later after reviewing this data.

III. Valuing the Benefits of Distributed Generation

Q. Do the proposed rates account for systemwide benefits?

A. No, with the sole exception of transmission-system benefits that can be accounted for in the transmission rate. As discussed in DOER's initial comments and elsewhere, DG has benefits in a variety of areas including deferral of distribution and transmission costs, improved reliability, and other societal benefits, such as, for instance, environmental impacts of air emissions from centralized sources of generation.

Q. How would you go about quantifying the benefits of distributed generation?

A. The definition of distributed generation found in the Restructuring Act mentions avoided costs as a characteristic of DG installations. There have been numerous studies that have estimated a number of benefits to DG. A recent review of 30 studies was completed by the National Renewable Energy Laboratory (NREL) and showed that distribution and transmission capacity deferral was a benefit mentioned in 24 and 21 of those studies, respectively[3].

Q. As stated in the Company's Testimony (at 8), the Department has recognized DG as a "generation resource option." Do you know of any studies or analytical work that has shown DG to be a generation resource option?

A. Yes. For example, see a recent report by Clean Power referenced in Exhibit DOER-AEP-1. In this study, the authors show potential benefits to a utility company of installing distributed

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[3] See Exhibit DOER-AEP-1, DER Benefit Analysis Studies: Final Report, September 2003, NREL, Table 5.

photovoltaics. In addition, the response of the Company to Information Request NEDGC-2-4 contains examples of the use of DG as a resource for delivery of electric power.

Q. Do you know of any studies that discuss DG benefits to other customers or systemwide benefits? If so, shouldn't the proposed rates pay DG customers for these benefits?

A. Yes to both questions. We have compiled a summary of quantification of benefits from DG included in studies we have reviewed. Please see Exhibit DOER-AEP-2. The recent study from the Cape Light Compact entitled "End User Distributed Generation Applications" is of particular relevance to this proceeding since it is located in NSTAR's service area.

Q. Is it possible for utility companies to benefit from installation of DG equipment?

A. Yes. As an example, I refer again to the recent report by Clean Power. In addition, utility companies in Massachusetts face service quality indices ("SQI") and get penalized if actual performance is below an indexed level. Installation of DG may lead to instances where utility companies benefit through avoidance of SQI penalties, yet do not reimburse DG customers for this benefit. [4]

Q. In your view, are customers with on-site generation the same as other customers in similar classes?

A. No. In fact, as I will discuss later in my testimony, I believe that they deserve a treatment that results in rates that encourage the development of beneficial technologies as compared to existing rates. I have seen no evidence to date that supports the conclusion that on-site generation poses additional cost to the distribution companies in the state. To the contrary, we have seen numerous examples of reasons to place a high value on the deployment of on-site generation.

Q. Does DOER rely on any existing state policy, precedent, or directive that leads you to support more favorable standby rates?

[4] See the Company's SQI Reports, the link for which is shown on Exhibit DOER-AEP-1.

A. In general, state policy and precedent dictate a more favorable treatment than that proposed by NSTAR. For instance:

1) The Massachusetts Legislature enacted a law limiting Exit Fees in the Restructuring Act. That law creates a standard for absorbing revenue loss up to 10% from DG before assessing a change in transition charges for those customers. As is addressed below, it also favors the beneficial technologies.

2) The Department's own standard for determining the cost effectiveness ofenergy efficiency programs (DTE 98-100) provides a method of valuing the impact of reduced kilowatthours and includes the benefit of reduced transmission and distribution costs from reduced capacity as a result of the program. At minimum, the standby rate should, similarly, incorporate reduced distribution costs from the reduction of kilowatthours used. It is notable that the distribution companies each have a demand side management plan that assures the cost effectiveness of programs by including the value of reduced load. In addition to the benefits from reduced usage, the rate should factor in the reality that some DG will inevitably run during peak times, reducing the impact of system costs during peak congestion periods.

3) The Department's recent Order on DG directs the DG Collaborative to address and provide recommendations on the role of DG in distribution planning (DTE 02-38, 2004 at page 40), which suggests that it is generally accepted that some level of benefits exist. This will undoubtedly require an ongoing, in-depth review of all benefits in order for the Collaborative to make its consensus-based recommendations to the Department.

4) When the Department approved the NEES/EUA Merger (D.T.E. 99-47), its Order essentially rejected the proposal for a method of determining a tariff for backup rates and provided a standard for such review.

Q. Are you aware of any further state policies or regulations currently in development that are likely to recommend that DG or DG rates should be treated more favorably?

A. Yes. I understand that this Administration will soon be releasing its State Climate Change Action Plan. It is anticipated that this document will state the importance of implementing policies that will not hinder the development of beneficial on-site technologies used to generate electricity, naming specifically renewables, cogeneration, and fuel cells. In addition, the MA Department of Environmental Protection is expected to release its emissions regulations for distributed generation for public comment in the near future (310 CMR 7.20 "Engines and Combustion Turbines"). Those regulations are anticipated to include a treatment for CHP that may facilitate the installation of such beneficial technologies which could displace higher air emissions from other sources.

Q. Mr. LaMontagne suggests that the distribution system needs to be configured exactly the same way for standby customers as it is for non-standby customers, thus justifying basing these rates on the current rates. Do you agree?

A. No. By definition, distributed generation customers have access to generation resources that non-DG customers do not. As such, their usage patterns will differ from time to time. The complete failure of a distributed generation resource at the coincident peak with non-DG users of similar usage may result in usage patterns of distribution systems that are identical, and, therefore, require that the distribution system be configured exactly the same way. However, the Company has not provided any data concerning the probability of such an event and whether the distribution system should be configured or planned to account for such events.

Q. Are there any corollaries between energy efficiency as a generation resource and distributed generation as a generation resource?

A. Yes. Energy efficiency and load management can be classified along with distributed generation as “distributed resources.” In a recently released report conducted by the Governor's Task Force on Electric Reliability and Outage Preparedness, distributed resources consist of:

> ... resources applied at the customer's location, a substation, or other load supply point in the system. Distributed resources are of two types: (1) demand response, including load response programs and energy efficiency initiatives; and (2) distributed generation ('DG'). In a demand response program, commercial and industrial electricity users can receive incentive payments if they reduce their electricity consumption or operate generation in response to high real-time wholesale electricity prices, or when reliability of the region’s grid is stressed. DG is “a generation facility or renewable energy facility connected

directly to distribution facilities or to retail customer facilities which alleviate or avoid transmission or distribution constraints or the installation of new transmission facilities or distribution facilities." G.L. c. 164, § 1.

Governor's Task Force on Electric Reliability and Outage Preparedness Report at page 25.

Q. Based on NStar's testimony and cost causation logic, as customers install energy-efficiency (EE) measures in increasing fashion are they actually being increasingly subsidized by other customers?

A. Yes, in that a customer that installs EE measures no longer contributes as much revenue to the Company's overall revenue needs. Assuming the company requires this lost revenue to pay for costs incurred by this customer, a shifting of cost recovery to other customers is necessary. I believe that the benefits of EE measures are well documented and such a shift has beneficial impacts on both the affected customer and the distribution system in general.

Q. If costs associated with load reduction are the same for EE and distributed generation, shouldn't the cost recovery mechanisms be the same?

A. Yes. Strangely, however, the cost recovery methods differ among the two groups. For example, under current rates, a customer that uses a distributed generation source and a customer that reduces his usage by the same amount through demand-side management would face the same bills at the end of the month. If the proposed rates were approved, these bills would differ. It is unclear, from a cost-causation perspective, how this can be appropriate.

IV. Impact of Proposed Rates on Development of Distributed Generation

Q. What is the impact of the proposed standby rate on the various on-site generation technologies?

A. Based on an analysis we conducted at DOER, I believe that this standby rate treatment will have severe adverse impacts on installation of all on-site electric generation technologies (see Exhibit DOER-AEP-3).

Q. Maintenance service, by definition, is standby service that can be planned in advance. Do existing rates for maintenance service reflect the expectation that standby rates that would apply to these services should be lower than non-maintenance standby service?

A. Yes but the Company has proposed to close these existing rates and replace them with rates that are less favorable. The Company acknowledges that "Maintenance Service was typically available during off-peak months and its pricing reflects this timing."[5] This logic can also be applied to non-maintenance standby customers that would only suffer outages during non-peak periods of the day. The Company makes no attempt to calculate the expectation of such outages and account for it in its rate design.

Q. Haven't the costs for non-firm interruptible standby service already been largely incurred?

A. Yes, in certain cases. For example, it is easy to think of customers that currently receive non-standby service to maintain the same level of service and distribution system costs and investments even after such a customer were to take non-firm interruptible service. Rates would be lower only if the utility company were to shift those assets (and costs) for use to other customers. The Company has not shown any workpapers to indicate that this would be the case. In addition, the Company has stated that "portions of the network (those closest to the customer) are dedicated to serve the peak needs of specific customers."[6]

Q. If so, how can one justify a lower rate for these customers?

A. Based on the response to the prior question, it is unclear from a cost-causation perspective that non-firm customers would be able to receive lower rates. Rather, it is probably the case that recovery of distribution system costs is currently done in a more aggregate fashion than the Company claims, and that there is greater flexibility in the planning and configuration of distribution systems than the Company acknowledges.

Q. Similarly, cannot the utility experience a pattern with firm standby customers?

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[5] LaMontagne Direct Testimony, page 4.
[6] LaMontagne Direct Testimony, page 15.

A. Yes, where such patterns exist. However, the Company has claimed that standby customers' usage of the distribution is potentially uncertain to such a degree that no possibility, short of non-firm service, exists for planning the system for patterns in usage of this customer group. The Company has not provided any evidence that documents the extent of variation in existing standby customers. Presumably, there may be customers who have a history of predictable and/or stable use of standby service. These characteristics should be accounted for in the rate design applicable to these and other standby customers.

Q. Might there be instances where a DG customer would not use his generator at the expected output or nameplate capacity? If so, do not the proposed rates overcharge DG customers?

A. Yes, it is conceivable that due to a variety of reasons, such as high fuel costs relative to non-distributed generation options, a customer would elect to alter the level of power taken from its distributed generation resource. DG customers should be able to specify a level of contract demand relevant to their needs.

Q. PURPA had a number of objectives, as quoted in NSTAR's testimony. Do the proposed rates attempt to meet these objectives?

A. No. Some of the objectives, notably a reduced reliance on fossil fuels, are even more relevant today. Massachusetts energy policy includes a renewable portfolio standard (RPS) that addresses this issue from the demand side, by requiring minimum purchase levels of electricity from renewable generation sources. On the other hand, supply has to be able to support these minimum levels, and the proposed rates would serve to increase rates to such a large degree that a large portion of customers who are considering installation of clean, renewable DG will be less likely to choose to employ such technologies.

Q. The proposed rates filed by NSTAR revise numerous features of the existing rate. In your view, is it appropriate to make these revisions?

A. No. The proposed rate design and terms and conditions place an undue burden on customers with distributed generation by doing the following:

1) the rate moves all but energy kWh charges into the fixed demand component of the bill. The result of this is that customers with on-site generation would essentially only be avoiding the energy costs, thus reducing the economic benefits of the installation.
2) the tariff reduces the threshold for applicability from the 100kW included in the existing Cambridge rate to 60kW, thus broadening the impact of the change in that service territory.
3) Aspects of meter ownership should not be proposed and determined in this proceeding. I would like to highlight that the Department has clearly provided for this meter ownership issue to be addressed by the DG Collaborative (DTE 02-38, 2004). As result, it is inappropriate for the Company to attempt a premature resolution to this in this proceeding.

Q. Are the proposed rates too high in that they discourage development of DG?

A. Yes. I performed a simple bill impact analysis to show the decision calculus of a sample customer considering installation of either a base-load or intermittent form of DG. The analysis can be found in Exhibit DOER-AEP-3. As shown, for a customer of this size and load profile (300 kW with 194,400 kWh monthly usage), the potential T&D cost savings of DG installations are largely absorbed by the proposed rates and would make adoption of DG for this customer economically unfeasible, especially for intermittent resources. Renewable energy sources such as wind and solar are generally considered intermittent resources.

Q. Are there additional provisions that should be considered?

A. The proposal makes no exception for distributed generation using more beneficial technologies, such as renewables, combined heat and power, or fuel cells. These technologies provide system benefits at low emissions and with alternative fuels, thus helping the region reduce its dependence on fossil fuels like coal and oil. DOER supports consideration of exemptions that would favor the use of beneficial technologies, particularly as we await the results of the DG Collaborative's two year process of developing a benefits valuation method. The benefits of these technologies justify an exemption. We may be missing a window of opportunity in the development of these technologies if we fail to adopt policies now which encourage their installation, particularly in the Boston/NEMA areas. I am also aware that the jurisdictions of New York and California have adopted these types of exemptions.

Q. Would the proposed rates, if enacted, hinder development of renewable technologies?

A. Yes. Based on the analysis presented in Exhibit DOER-AEP-3, the proposed rates create large barriers to wide scale deployment of DG. The rates are simply too high to promote or even support large additions to the state portfolio of DG. Similar to decisions concerning adoption of energy efficiency measures, customers need to see bill savings that can justify investment in DG technologies. This lack of wide scale deployment will prohibit the achievement of the full benefits of DG. As the Company has stated in its response to Information Request NEDGC-2-4, "The presence of distributed generation on the Company's system is not currently widespread, with no known locations where more than one DG customer is served by the same distribution circuit. As a result, there is no diversity factor that can be applied to any portion of the Company's distribution system that would allow the Company to incorporate changes in the otherwise applicable distribution system planning process. In the future, it is possible that multiple DG customers served by the same circuit may provide sufficient diversity among their standby load requirements to allow the Company to incorporate the presence of such multiple DGs in the Company's transmission/distribution system planning process." It is unclear how the proposed rates assist in bringing about this future. In addition, lack of investment in clean DG will further exacerbate an increasingly tight supply of renewable generation to meet the needs of the region's various RPS requirements. As more states adopt RPS requirements, prices for certificates continue to rise, indicating tight supply. See Exhibit DOER-AEP-4, showing recent offer prices close to or at capped levels. As these prices rise, all customers must pay for compliance with RPS requirements. Finally, DG manufacturers and installers represent an advanced manufacturing cluster that is prominent in the Northeast and specifically, in Massachusetts. Many of these industries have projected growth rates much higher than the average growth rates for a number of other prominent Massachusetts industries. Thus, promotion of such industries that support renewable generation is compatible with promoting job growth in the Commonwealth by taking advantage of the region's educational and amenity assets.

Q. Does this conclude your testimony?

A. Yes.

Exhibit DOER-AEP-1

Internet Links to Documents
Referenced in the Alvaro E. Pereira Testimony

1. NREL's "DER Benefits Analysis Studies: Final Report" (Sept 2003)
   http://www.nrel.gov/docs/fy03osti/34636.pdf

2. Clean Power Study
   http://www.clean-power.com/research/distributedgeneration/NevadaPower2003.pdf

3. The Cape Light Compact's "End User Distributed Generation Applications" Study and "Final Utility Distributed Generation Report":
   http://www.capelightcompact.org/ (Click on item #8 and #11)

4. Annual Service Quality Reports of the NSTAR Companies
   http://www.state.ma.us/doer/dg/dg.htm

5. The Restructuring Act and Exit Fees (Ctr+F: "exit")
   http://www.state.ma.us/legis/laws/seslaw97/sl970164.htm

6. Cost Effectiveness of DSM Programs (DTE 98-100)
   http://www.state.ma.us/dpu/electric/98-100/finalguidelinesorder.htm

7. Department's Order on DG (DTE 02-38, 2004)
   http://www.state.ma.us/dpu/catalog/6819.htm

8. The NEES/EUA Merger Settlement (DTE 99-47)
   http://www.state.ma.us/dpu/electric/99-47/finalorder31400.htm

9. "Report of the Governor's Task Force on Electric Reliability and Outage Preparedness"
   http://www.state.ma.us/dpu/225repgtf.htm

10. Distributed Generation: Understanding the Economics (ADLittle)
    http://www.eere.energy.gov/distributedpower/pdfs/library/adl_dg_econ.pdf

11. The Restructuring Act – Renewable Portfolio Standard and the Renewables Trust Fund (Ctr+F: "renewables")
    http://www.state.ma.us/legis/laws/seslaw97/sl970164.htm

Exhibit DOER-AEP-2

Benefits from Installation of DG – Results of Selected Studies

Distributed Generation System Benefits			
	Benefit Valuations		
	Low	**High**	**Notes**
1. Cape Light Compact End User DG Study	$/kW-yr		
Transmission capacity benefit (peak operation only)	1.60	8.00	Nstar and CommElectric Specific Data
Distribution capacity benefit (peak operation only)	4.30	31.00	Nstar and CommElectric Specific Data
Ancillary Services benefit	8.00	12.00	
Reliability benefit	21.70	43.00	CommElectric Specific Data, C&I
Total Benefit	35.60	94.00	
2. Performance and Value Analysis of PV Power Plant ($1995)	$/kW-yr		
Reliablity Benefit	4.00	4.00	
Substation Benefit	16.00	88.00	
Transmission Benefit	45.00	45.00	
Capacity Ben	12.00	53.00	Includes Avoided Generation Capacity
Total Benefit	77.00	190.00	
3. ADL White Paper - DG: Understanding the Economics	Typical Benefit ($/kw-yr)		
Reduced T&D Losses	50.00		
T&D Upgrade Deferral	30.00		
VAR Support	35.00		
Total Benefit	115.00		

Source URLs:

1. http://www.capelightcompact.org/FIN%20END%20USER%20DG%20RPT.pdf
2. http://www.clean-power.com/research/distributedgeneration/KermanAPC.pdf
3. http://www.eere.energy.gov/distributedpower/pdfs/library/adl_dg_econ.pdf

<u>Illustrative Bill Impact Analysis of Potential DG Customer</u>
Baseload vs. Intermittent Distributed Generation
<u>Boston Edison</u>

NSTAR, Boston Edison, Rate G-2, M.D.T.E. No. 131B, pages 1-2
DG Summer Month RATE EXAMPLE – Baseload DG Technology

	Customer without DG	Customer with DG and Supplemental Service (200 kw DG & 100 kw Supplemental)
	Rates ($/mo)	
Customer Charge	18.19	18.19
Total Distribution (demand) Costs	6,066.00	7,278.00
Distribution (energy) Total	1,144.67	532.67
Transition (energy) Total	1,585.85	1,156.23
Transmission (demand)	1,316.60	408.60
Transmission (energy)	8.93	3.23
Supplier Services	9,914.40	3,672.00
SBC	972.00	360.00
SUBTOTAL (Customer, T&D, SBC)	11,112.24	9,756.92
TOTAL (including supply)	21,026.64	13,428.92
AVOIDED RETAIL COSTS per KW (assuming 200 kw installation)		37.99

Source: DOER, Boston Edison Proposed Rates

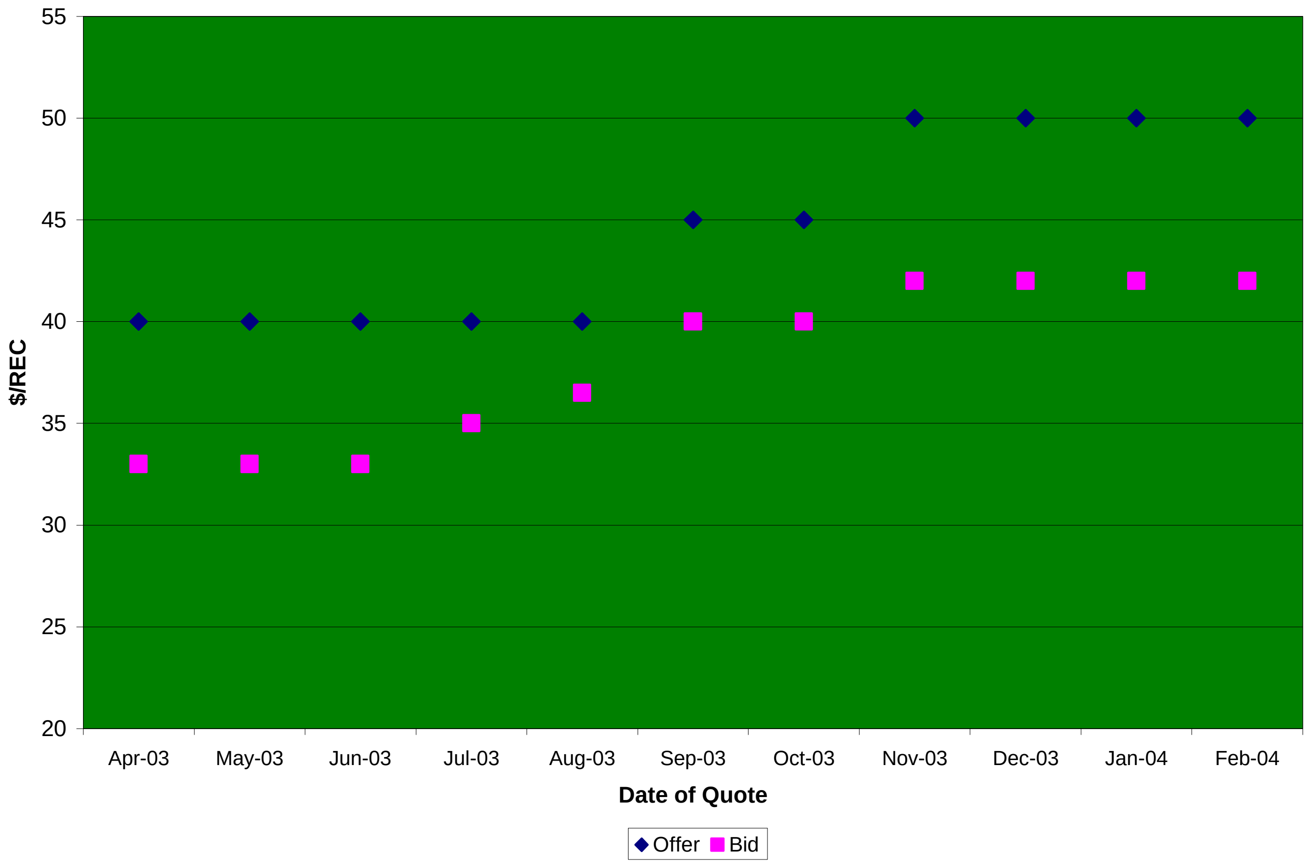
NSTAR, Boston Edison, Rate G-2, M.D.T.E. No. 131B, pages 1-2
DG Summer Month RATE EXAMPLE – Intermittent DG Technology

	Customer without DG	Customer with DG and Supplemental Service (200 kw DG & 100 kw Supplemental)
	Rates ($/mo)	
Customer Charge	18.19	18.19
Total Distribution (demand) Costs	6,066.00	7,278.00
Distribution (energy) Total	1,144.67	928.67
Transition (energy) Total	1,585.85	1,434.22
Transmission (demand)	1,316.60	408.60
Transmission (energy)	8.93	3.23
Supplier Services	9,914.40	7,711.20
SBC	972.00	756.00
SUBTOTAL (Customer, T&D, SBC)	11,112.24	10,826.91
TOTAL (including supply)	21,026.64	18,538.11
AVOIDED RETAIL COSTS per KW (assuming 300 kw customer)		12.44

Source: DOER, Boston Edison Proposed Rates

Exhibit DOER-AEP-4

Massachusetts 2004 Renewable Energy Certificate Prices



Source: Evolution Markets, LLC